

APPENDIX A

STATE AND FEDERAL COMPLIANCE ORDERS AND NOTICES

EPA FOV 5-99-IL-28 (dated 6-8-99)

EPA NOV 5-01-IL-04 (dated 1-19-01)

EPA FOV 5-01-IL-11 (dated 7-13-01)

IEPA Violation Notice A-2002-00346 (dated 11/13/02)

IEPA Violation Notice E-2003-00004 (dated 1-13-03)

LDEQ Notice of Violation and Potential Penalty AE-NP-99-0226 (dated 10-29-99)

LDEQ Compliance Order and Notice of Potential Penalty AE-CN-01-0304 (dated 6-6-02)

LDEQ Compliance Order and Notice of Potential Penalty AE-CN-02-0191 (dated 3-10-03)

TCEQ Agreed Order Docket No. 2001-1469-AIR-E (dated February 2004)

TNRCC Agreed Order Docket No. 1999-0057-AIR-E (dated June 2002)

APPENDIX B

LIST OF HYDROCARBON FLARING DEVICES

Corpus Christi East Refinery

Fluor Flare

Cumene Flare

Corpus Christi West Refinery

Flare

Lemont Refinery

844C-1 North Plant Flare

844C-2 South Plant Block 2 Flare

844C-3 South Plant Block 3 Flare

844C-4 Needle Coker Flare

844C-5 Alky Flare

Lake Charles Refinery

328B-1 Flare Alky

330B-4 Flare NGL/Girbitol

343B-5 Flare Central

343B-6 Flare Central

343B-7 Flare Central

319B-8 Flare C4 Recovery

315B-9 Flare Benzene

327B-11 Flare C-Ref/CK II

320B-12 Flare Unicracker

399B-16 Flare CFH

360CB-701 (CB-11) PFU

CA1001 CLAW

B-104 COP/TIER II

Paulsboro Refinery

Flare

APPENDIX B-1

LIST OF NSPS HYDROCARBON FLARING DEVICES

Corpus Christi East Refinery

Fluor Flare

Cumene Flare

Corpus Christi West Refinery

Flare

Lemont Refinery

844C-1 North Plant Flare

844C-2 South Plant Block 2 Flare

844C-3 South Plant Block 3 Flare

844C-4 Needle Coker Flare

844C-5 Alky Flare

Lake Charles Refinery

327B-11 Flare C-Ref/CK II

320B-12 Flare Unicracker

399B-16 Flare CFH

360CB-701 (CB-11) PFU

CA1001 CLAW

B-104 COP/TIER II

Paulsboro Refinery

Flare

APPENDIX B-2

LIST OF NSPS ACID GAS FLARING DEVICES

Corpus Christi East Refinery

Acid Gas Flare

SWS Flare

Corpus Christi West Refinery

Acid Gas Flare

SWS Flare

Lemont Refinery

844C-2 South Plant Block 2 Flare

844C-3 South Plant Block 3 Flare

Lake Charles Refinery

327B-11 Flare C-Ref/CK II

320B-12 Flare Unicracker

APPENDIX C

LIST OF CITGO HEATERS AND BOILERS

INFORMATION REDACTED AS CONFIDENTIAL BUSINESS INFORMATION

SEQ No.	Unit ID	Heat Input Capacity, MMBTU/Hr	2001 NOx Emissions, TPY	2002 NOx Emissions, TPY	2001 EIO Firing Rate, MMBTU/Hr	2002 EIO Firing Rate, MMBTU/Hr	2001 Utilization Percentage	2002 Utilization Percentage	NOx Emission Factor, Basis
	Design/Permit								
LAKE CHARLES REFINERY									
79	Boiler B-1,B-1A	890.6	2461.8	2493.3	803.0	813.2	Redacted	Redacted	F&TS Testing
145	Furnace B-503,504,505	700.0	172.9	197.7	415.6	475.1	Redacted	Redacted	Stack Test (Permit - 2615(M-2))
77	Boiler B-1C	616.7	474.9	505.5	349.8	372.3	Redacted	Redacted	F&TS Testing
78	Boiler B-1B	531.6	450.3	471.0	374.5	391.7	Redacted	Redacted	AP-42
25	Furnace B-4	456.6	242.6	218.9	403.5	364.2	Redacted	Redacted	AP-42
26	Furnace B-104	456.6	280.1	289.9	456.8	472.8	Redacted	Redacted	F&TS Testing
135	Boiler B-5A	337.6	81.3	76.5	185.6	174.7	Redacted	Redacted	Stack Test (PSD-LA-577)
136	Boiler B-5	337.6	92.9	89.6	212.1	204.6	Redacted	Redacted	Stack Test (PSD-LA-577)
87	Furnace B-403,404,405	330.0	46.7	54.7	183.8	215.3	Redacted	Redacted	F&TS Testing
80	Boiler B-2	267.1	193.4	181.2	160.9	150.7	Redacted	Redacted	AP-42
81	Boiler B-2A	267.1	132.6	117.8	168.2	149.4	Redacted	Redacted	F&TS Testing
141	Furnace B-1,2,3,4,5	245.0	119.8	136.1	134.7	153.1	Redacted	Redacted	Stack Test (Permit - 2615(M-2))
82	Boiler B-3,B-3B	229.5	303.9	309.5	252.8	257.4	Redacted	Redacted	AP-42
83	Boiler B-3A,B-3C	229.5	155.0	153.7	128.9	127.8	Redacted	Redacted	AP-42
144	Furnace B-501,502,506	198.5	73.3	69.8	88.2	83.9	Redacted	Redacted	Stack Test (PSD-LA-222)
107	Furnace B-102 - B-106	185.0	92.2	65.6	76.7	54.6	Redacted	Redacted	AP-42
34	Boiler BF-4	167.0	43.0	0.0	37.4	0.0	Redacted	Redacted	AP-42
139	Furnace B-201	158.8	110.7	93.3	158.0	133.2	Redacted	Redacted	F&TS Testing
140	Furnace B-202	158.8	90.5	87.1	150.6	144.8	Redacted	Redacted	AP-42
48	A Cat Furnace B-6	156.2	100.4	94.4	83.5	78.5	Redacted	Redacted	AP-42
50	C Cat Furnace B-6	156.2	24.5	29.1	68.3	80.9	Redacted	Redacted	F&TS Testing
31	Boiler BF-1	139.0	114.3	138.8	95.1	115.4	Redacted	Redacted	AP-42
32	Boiler BF-2	139.0	124.6	140.9	103.7	117.2	Redacted	Redacted	AP-42
33	Boiler BF-3	139.0	136.4	134.5	113.4	111.9	Redacted	Redacted	AP-42
177	Furnace B-101	116.9	18.0	13.0	97.6	70.6	Redacted	Redacted	Stack Test (Permit - 2308(M-2))
14	Furnace BA-1,2A&2B	115.6	102.2	110.5	85.0	91.9	Redacted	Redacted	AP-42
69	Furnace B-101	112.9	70.0	92.4	85.7	101.3	Redacted	Redacted	2001 - AP-42/ 2002 - Stack Test (Permit - 2714(VO))
70	Furnace B-201	109.7	74.6	92.1	91.3	101.0	Redacted	Redacted	2001 - AP-42/ 2002 - Stack Test (Permit - 2714(VO))
94	Furnace B-1C	104.7	134.5	143.7	111.8	119.5	Redacted	Redacted	AP-42
95	Furnace B-2C	98.2	47.0	46.4	109.4	108.1	Redacted	Redacted	AP-42
178	Furnace B-102	88.0	14.4	10.7	78.4	58.4	Redacted	Redacted	Stack Test (Permit - 2308(M-2))
49	B Cat Furnace B-6	81.4	16.6	15.2	38.6	35.5	Redacted	Redacted	AP-42
1	Furnace BA-1	77.5	33.4	37.4	77.8	87.1	Redacted	Redacted	AP-42
2	Furnace BA-101	77.5	33.5	23.1	78.0	70.3	Redacted	Redacted	2001 - AP-42 2002 - AP-42 - Low Nox burner
65	Furnace B-201	75.6	41.7	44.3	97.1	103.2	Redacted	Redacted	AP-42
72	Furnace B-101	74.8	22.0	23.3	51.2	54.3	Redacted	Redacted	AP-42
73	Furnace B-101 #2	74.8	22.0	23.3	51.2	54.3	Redacted	Redacted	AP-42
19	Furnace BA-1 & 2	68.3	11.3	11.3	26.4	26.2	Redacted	Redacted	AP-42
63	Furnace B-201	64.8	22.2	24.9	51.8	58.0	Redacted	Redacted	AP-42
6	Furnace N-2A	64.7	20.2	20.3	47.1	47.2	Redacted	Redacted	AP-42
7	Furnace N-2B	64.7	23.2	21.1	54.0	49.2	Redacted	Redacted	AP-42
8	Furnace N-2C	64.7	21.1	20.9	49.2	48.7	Redacted	Redacted	AP-42
17	Furnace BA-1 & 2	64.6	19.9	20.1	46.3	46.8	Redacted	Redacted	AP-42
84	Furnace B-401	60.4	17.5	15.7	40.8	36.5	Redacted	Redacted	AP-42
74	Furnace B-5	58.4	14.0	14.2	32.5	33.1	Redacted	Redacted	AP-42
85	Furnace B-406	57.3	10.6	11.5	24.8	26.7	Redacted	Redacted	AP-42
86	Furnace B-402	55.9	14.3	16.2	33.3	37.8	Redacted	Redacted	AP-42
64	Furnace B-202	53.0	18.3	16.6	42.7	38.7	Redacted	Redacted	AP-42
66	Furnace B-2A	44.5	19.6	21.1	45.8	49.1	Redacted	Redacted	AP-42
91	Furnace B-102	43.3	27.7	23.3	40.1	33.7	Redacted	Redacted	Stack Test (Permit - 74(M-3))
67	Furnace B-1 #1	39.0	24.2	22.4	56.3	52.1	Redacted	Redacted	AP-42
68	Furnace B-1 #2	39.0	24.2	22.4	56.3	52.1	Redacted	Redacted	AP-42
Totals		9543	7039	7106					

Those units identified with this checkmark are to be tested for NOx emissions. With prior consent from EPA, CITGO may substitute any other heater or boiler with a design firing rate > 100 MMBtu/hr and for which AP-42 factors are currently being used to estimate the baseline NOx emissions.

APPENDIX C

LIST OF CITGO HEATERS AND BOILERS

INFORMATION REDACTED AS CONFIDENTIAL BUSINESS INFORMATION

Unit ID	Heat Input Capacity, MMBTU/Hr Design/Permit	1999 NO _x Emissions, TPY	2000 NO _x Emissions, TPY	1999 Firing Rate MMBTU/Hr	2000 Firing Rate MMBTU/Hr	1999 Utilization Percentage	2000 Utilization Percentage	NO _x Emission Factor, Basis
LEMONTE REFINERY								
430B-1	325.0	181.7	198.9	183.9	201.3	Redacted	Redacted	Previously used AP-42, 5th ed. (3/98), Table 1.4-2 (factor = 0.274351 lb./MMBtu). 10/10/01 stack testing by ARI resulted in current factor.
111B-1A	322.0	250.0	261.1	277.2	289.6	Redacted	Redacted	Based on 10/9/2000 stack test by ARI
111B-1B	322.0	234.2	250.2	259.8	277.5	Redacted	Redacted	Based on 10/9/2000 stack test by ARI
431B-19	249.0	37.8	39.0	118.8	122.6	Redacted	Redacted	Previously used AP-42, 5th ed. (3/98), Table 1.4-2 (factor = 0.27451 lb./MMBtu). 9/6/01 stack testing by ARI resulted in current factor.
431B-Replacement	249.0	0.0	0.0	0.0	0.0	Redacted	Redacted	Replacement for 431B-19 in 2002. Designed for 0.06 lb. NO _x /MMBtu.
111B-2	219.8	104.8	38.5	148.6	145.9	Redacted	Redacted	4/22/98 stack test = 0.161 lb/MMBtu. ULNB installed March '00. EF = 0.06 lb/MMBtu (est). 10/19/2000 stack test by ARI showed EF = 0.036 lb./MMBtu.
116B-1	125.6	103.8	104.1	86.3	86.6	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
123B-2	121.2	91.9	104.4	76.4	86.8	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
112B-1	121	0.0	0.0	0.0	0.0	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
116B-2	106.9	129.2	104.0	107.5	86.5	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
109B-62	103.0	37.6	64.9	53.7	92.6	Redacted	Redacted	Permit Basis is 0.16 lb./MMBtu. AP 42, 5th ed. (3/98), Table 1.4-2 is 0.098039.
118B-1	93.8	18.9	22.2	44.0	51.7	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
113B-1	88.8	16.38	16.1	71.9	70.8	Redacted	Redacted	required by SEP. 9/97 stack test
113B-2	88.8	15.8	15.6	69.5	68.5	Redacted	Redacted	Permit, 9/97 stack test of 113B-1
113B-3	88.8	26.8	27.4	71.7	73.2	Redacted	Redacted	Permit, 10/85 stack test results
125B-2	82.3	40.4	37.0	94.0	86.2	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
125B-1	69.3	31.6	13.2	73.5	30.8	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
123B-3	55.3	9.9	10.2	23.2	23.8	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
123B-1	45.6	7.9	9.9	18.3	23.0	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
123B-5	42.0	12.8	12.2	29.9	28.4	Redacted	Redacted	AP-42, 5th ed. (3/98), Table 1.4-2
Totals	2919	1352	1329					

APPENDIX C

LIST OF CITGO HEATERS AND BOILERS

INFORMATION REDACTED AS CONFIDENTIAL BUSINESS INFORMATION

		Heat Input Capacity, MMBTU/Hr	2001 NO _x Emissions, TPY	2002 NO _x Emissions, TPY	2001 EIQ Firing Rate MMBTU/Hr	2002 EIQ Firing Rate MMBTU/Hr	2001 Utilization Percentage	2002 Utilization Percentage	NO _x Emission Factor, Basis
Unit ID		Design/Permit							
CORPUS CHRISTI REFINERY									
East Plant		320	59.9	47.3	173.8	171.4	Redacted	Redacted	NO _x CEM
East Plant		311.8	94.9	105.4	154.7	171.9	Redacted	Redacted	AP-42
East Plant		120	39.3	38.6	118	116.1	Redacted	Redacted	Stack Test (5/99)
East Plant		219	82.6	99.4	99.2	119.5	Redacted	Redacted	AP-42
East Plant		121.7	80.9	88.9	97.2	106.8	Redacted	Redacted	AP-42
East Plant		223	16.7	14.5	95.9	108.3	Redacted	Redacted	NO _x model
East Plant		116	40.3	44.4	92.1	101.4	Redacted	Redacted	AP-42
East Plant		200.6	41.9	43.5	79.5	78.2	Redacted	Redacted	NO _x model
East Plant		252.4	120.7	142.4	232.3	196.8	Redacted	Redacted	AP-42
East Plant		48	19.4	19.2	44.2	43.9	Redacted	Redacted	AP-42
East Plant		41.6	13.2	12.7	30.1	29	Redacted	Redacted	AP-42
East Plant		164.3	0.0	0.0	0.0	0.0	Redacted	Redacted	AP-42
East Plant		400	130.4	132.2	391.6	397.1	Redacted	Redacted	Stack Test (5/99)
East Plant		52.8	10.5	3.9	23.9	15.8	Redacted	Redacted	AP-42
East Plant		52.8	10.1	4.1	23	16.3	Redacted	Redacted	AP-42
West Plant		290.6	45.0	47.8	205.4	222.4	Redacted	Redacted	NO _x model
West Plant		144.8	74.4	71.6	121.4	116.8	Redacted	Redacted	AP-42
West Plant		132.7	58.2	62.1	94.9	101.2	Redacted	Redacted	AP-42
West Plant		76.6	32.6	31.8	74.4	72.7	Redacted	Redacted	AP-42
West Plant		82.3	27.9	29.4	67.7	71.5	Redacted	Redacted	Stack Test (1/15/98)
West Plant		98.9	25.7	21.8	50.2	42.5	Redacted	Redacted	Stack Test (3/26/84)
West Plant		98.9	21.6	20.3	46	43.4	Redacted	Redacted	Stack Test (3/22/84)
West Plant		48.2	19.4	20.9	44.4	47.7	Redacted	Redacted	AP-42
West Plant		98.9	17.2	17.4	39.3	39.8	Redacted	Redacted	AP-42
West Plant		49.9	15.9	13.7	36.2	31.3	Redacted	Redacted	AP-42
West Plant		62	7.5	7.7	26.5	27.1	Redacted	Redacted	Stack Test (1/16/98)
East Plant		16.2	197.5	201.3	20.8	20.4	Redacted	Redacted	AP-42
East Plant		59.4	166.6	154.1	12	11.1	Redacted	Redacted	AP-42
East Plant		11.1	1.6	1.6	1.62	1.62	Redacted	Redacted	AP-42
Totals		3915	1472	1498					

Note 1

Note 1

Note 1: Utilizes YR 2000 NO_x emissions and Firing Rate for baseline for the #4 Platformer and the Platformer Compressors.

Heat Input Capacity, MMBTU/Hr	2001 NO _x Emissions, TPY	2002 NO _x Emissions, TPY
16,377	9,862	9,933

APPENDIX D

DETERMINING THE OPTIMIZED ADDITION RATES OF CATALYST ADDITIVES AT THE FCCUs

I. PURPOSE

This Appendix defines a process by which CITGO shall determine for the FCCUs the Optimized Addition Rates for Low NOX Combustion Promoters, NOX Reducing Catalyst Additives and SO2 Reducing Additives during the Optimization Periods.

II. ESTABLISHING AN OPTIMIZED LOW NOX COMBUSTION PROMOTER ADDITION RATE

A. Overview. Establishing an Optimized Low NOX Combustion Promoter Addition Rate for the FCCUs is a three-step process: (1) establishing a minimum addition rate for the conventional combustion promoter that CITGO currently uses such that the effectiveness of the conventional combustion promoter is maintained (the “Minimum Conventional Combustion Promoter Addition Rate”); (2) replacing the conventional combustion promoter with a particular Low NOX Combustion Promoter at an addition rate that is the functional equivalent of the Minimum Conventional Combustion Promoter Addition Rate (the “Initial Low NOX Combustion Promoter Addition Rate”); and (3) increasing the addition rate up to two times the Initial Low NOX Combustion Promoter Addition Rate if the Initial Low NOX Combustion Addition Rate is not effective (the “Optimized Low NOX Combustion Promoter Addition Rate”).

B. “Effectiveness” Determinations. The effectiveness of conventional combustion promoter shall be determined by the following criteria: (1) afterburn is controlled adequately and regenerator temperature and combustion levels are adequately maintained; and

(2) temperature excursions are brought under control adequately. The effectiveness of Low NOX Combustion Promoter shall be determined by those two criteria and by whether a measurable reduction in NOX emissions occurs.

C. Establishing the Minimum Conventional Combustion Promoter Addition Rate.

CITGO shall reduce its historical usage of conventional combustion promoters to the point that the addition rate is the minimum necessary to retain the effectiveness of the conventional combustion promoter that CITGO is using ("Minimum Conventional Combustion Promoter Addition Rate").

D. Establishing the Initial Low NOX Combustion Promoter Addition Rate. Based on the activity of conventional combustion promoter historically used and the activity of the Low NOX combustion promoter, CITGO shall replace conventional combustion promoter with Low NOX Combustion Promoter at a rate that is the functional equivalent in promotion activity of the Minimum Conventional Combustion Promoter Addition Rate. This functionally equivalent rate shall be called the Initial Low NOX Combustion Promoter Addition Rate.

E. Establishing the Optimized Low NOX Combustion Promoter Addition Rate. If the Low NOX Combustion Promoter is not effective at the Initial Low NOX Combustion Promoter Addition Rate, CITGO shall increase, by up to two times, the Initial Low NOX Combustion Promoter Addition Rate. If, at two times the Initial Low NOX Combustion Promoter Addition Rate, the Low NOX Combustion Promoter is not effective, CITGO may discontinue the use of Low NOX Combustion Promoter.

III. **ESTABLISHING AN OPTIMIZED NOX REDUCING CATALYST ADDITIVE ADDITION RATE**

A. **Overview.** The Optimized NOX Reducing Catalyst Additive Addition Rate shall be determined by evaluating NOX emissions reductions and annualized costs at three different addition rates.

B. **The Increments.** The three addition rates or “increments” shall be:

- 1.0 Weight % NOX Reducing Catalyst Additive
- 1.5 Weight % NOX Reducing Catalyst Additive
- 2.0 Weight % NOX Reducing Catalyst Additive

Where Weight % is of the total catalyst added to the FCCU.

C. **The Procedure.** CITGO shall successively add NOX Reducing Catalyst Additive at each increment set forth above. Once a steady state has been achieved at each increment, CITGO shall evaluate the performance of the NOX Reducing Catalyst Additive in terms of NOX emissions reductions and projected annualized costs. The final Optimized NOX Reducing Catalyst Additive Addition Rate shall occur at the addition rate where either:

- (1) the FCCU meets 20 ppmvd NOX (corrected to 0% O₂) on a 365-day rolling average, in which case CITGO shall agree to accept limits of 20 ppmvd NOX (corrected to 0% O₂) on a 365-day rolling average basis at the conclusion of the Demonstration Period; or
- (2) the total annualized cost-effectiveness of the NOX Reducing Catalyst Additive used exceeds \$10,000 per ton of NOX removed as measured from an uncontrolled baseline (as estimated based on current operating parameters as compared to operating parameters during the baseline period); or
- (3) the Incremental NOX Reduction Factor is less than 1.8, where the Incremental NOX Reduction Factor is defined as:

$$\frac{PR_i - PR_{i-1}}{CAR_i - CAR_{i-1}} \quad \text{where:}$$

PR_i = Pollutant (NOX) reduction rate at increment i in pounds per day from the baseline model

PR_{i-1}	=	Pollutant (NOX) reduction rate at the increment prior to increment i in pounds per day from the baseline model
CAR_i	=	NOX Reducing Catalyst Additive Rate at increment i in pounds per day
CAR_{i-1}	=	NOX Reducing Catalyst Additive Rate at the increment prior to increment i in pounds per day

If the conditions of either (1), (2), or (3) above are not met at any addition rate less than 2.0

Weight % NOX Reducing Catalyst Additive, then the Optimized Addition Rate shall be 2.0

Weight % NOX Reducing Catalyst Additive.

If an additive limits the FCCU's ability to control CO emissions to below 500 ppmvd CO at 0% O₂ on an 1-hour basis or 100 ppmvd CO at 0% O_x on a 365-day basis, and cannot be reasonably compensated for by adjusting other parameters without adversely impacting conversion (yield selectivity) or processing rates, then the additive rate shall be reduced to a level at which the additive no longer causes such effects.

IV. ESTABLISHING AN OPTIMIZED SO₂ REDUCING CATALYST ADDITIVE ADDITION RATE

A. Overview. The Optimized SO₂ Reducing Catalyst Additive Addition Rate shall be determined by evaluating SO₂ emissions reductions and annualized costs at three different addition rates.

B. The Increments. The three addition rates or "increments" shall be:

5.0 Weight % SO₂ Reducing Catalyst Additive
7.5 Weight % SO₂ Reducing Catalyst Additive
10.0 Weight % SO₂ Reducing Catalyst Additive

Where Weight % is of the total catalyst added to the FCCU.

C. The Procedure. CITGO shall successively add SO₂ Reducing Catalyst Additive at

each increment set forth above. Once a steady state has been achieved at each increment, CITGO shall evaluate the performance of the SO₂ Reducing Catalyst Additive in terms of SO₂ emissions reductions. The final Optimized SO₂ Reducing Catalyst Additive Addition Rate shall occur at the addition rate where either:

- (1) the FCCU meets 25 ppmvd SO₂ (corrected to 0% O₂) on a 365-day rolling average and 50 ppmvd SO₂ (corrected to 0% O₂) on a 7-day rolling average, in which case CITGO shall agree to accept limits of 25 ppmvd SO₂ (corrected to 0% O₂) on a 365-day rolling average and 50 ppmvd SO₂ (corrected to 0% O₂) on a 7-day rolling average at the conclusion of the Demonstration Period;
- (2) the addition of SO₂ Reducing Catalyst Additive limits the FCCU feedstock processing rate or conversion (yield selectivity) capability in a manner that cannot be reasonably compensated for by the adjustment of other parameters, then the maximum addition rate shall be reduced to a level at which the additive no longer interferes with the FCCU processing or conversion rate; provided, however, that in no case, shall the maximum addition rate be less than 5.0 weight %; or
- (3) the Incremental SO₂ Pick-up Factor is less than 2.0, where the Incremental SO₂ Pick-up Factor is defined as:

$$\frac{PR_i - PR_{i-1}}{CAR_i - CAR_{i-1}} \quad \text{where:}$$

PR_i = Pollutant (SO₂) reduction rate at increment i in pounds per day from the baseline model

PR_{i-1} = Pollutant (SO₂) reduction rate at the increment prior to increment i in pounds per day from the baseline model

CAR_i = Pollutant (SO₂) Reducing Catalyst Additive Rate at increment i in pounds per day

CAR_{i-1} = Pollutant (SO₂) Reducing Catalyst Additive Rate at the increment prior to increment i in pounds per day

If the conditions of either (1), (2), or (3) above are not met at any addition rate less than 10.0 weight % SO₂ Reducing Catalyst Additive; then the Optimized Addition Rate shall be 10.0 weight % SO₂ Reducing Catalyst Additive. In no case shall the Optimized Addition Rate shall

be less than 5.0 weight % SO₂ Reducing Catalyst Additive.

APPENDIX E

NSPS SUBPART J COMPLIANCE SCHEDULE

FOR HEATERS AND BOILERS AND STREAMS IN FUEL GAS

Plant	Unit	Completion/Submittal Date
Corpus Christi East Refinery	Cumene Depropanizer Off-Gas	AMP 6 months after Date of Entry
Corpus Christi East Refinery	Hydrar Stabilizer OH Off Gas	AMP 6 months after Date of Entry
Corpus Christi East Refinery	Hydrar Stripper Off Gas	AMP 6 months after Date of Entry
Corpus Christi East Refinery	Hydrar Hydrogen	AMP 6 months after Date of Entry
Corpus Christi East Refinery	Hydrar Degassing Drum Off Gas	AMP 6 months after Date of Entry
Corpus Christi East Refinery	C4SHP DME Stripper Off Gas	AMP 6 months after Date of Entry
Corpus Christi East Refinery	Tanks 140 and 141 Vents	AMP 6 months after Date of Entry
Corpus Christi East Refinery	C5 Merox Disulfide Separator Spent Air Vent	AMP 6 months after Date of Entry
Corpus Christi East Refinery	Unibon Recycle Hydrogen Purge	AMP 6 months after Date of Entry
Corpus Christi West Refinery	Merox Disulfide Separator Spent Air Vent	AMP 6 months after Date of Entry
Lemont Refinery	114B-1	July 2005
Lemont Refinery	114B-2	July 2005
Lemont Refinery	114B-3	July 2005
Lemont Refinery	115B-1	July 2005
Lemont Refinery	115B-2	July 2005
Lemont Refinery	116B-1	July 2005
Lemont Refinery	116B-2	July 2005
Lemont Refinery	116B-3	July 2005
Lemont Refinery	116B-4	July 2005
Lemont Refinery	118B-1	July 2005

Plant	Unit	Completion/Submittal Date
Lemont Refinery	118B-51	July 2005
Lemont Refinery	122B-1	July 2005
Lemont Refinery	122B-2	July 2005
Lemont Refinery	123B-1	October 2005
Lemont Refinery	123B-2	October 2005
Lemont Refinery	123B-3	October 2005
Lemont Refinery	123B-4	October 2005
Lemont Refinery	123B-5	October 2005
Lemont Refinery	125B-1	July 2005
Lemont Refinery	125B-2	July 2005
Lake Charles Refinery	C-Reformer B-501	March 2005
Lake Charles Refinery	C-Reformer B-502	March 2005
Lake Charles Refinery	C-Reformer B-503	March 2005
Lake Charles Refinery	C-Reformer B-504	March 2005
Lake Charles Refinery	C-Reformer B-505	March 2005
Lake Charles Refinery	C-Reformer B-506	March 2005
Lake Charles Refinery	Boiler BF-1	September 2005
Lake Charles Refinery	Boiler BF-2	September 2005
Lake Charles Refinery	Boiler BF-3	September 2005
Lake Charles Refinery	Boiler BF-4	September 2005
Lake Charles Refinery	Boiler BF-5	September 2005
Lake Charles Refinery	Duo-Sol Furnace N-2A	September 2005
Lake Charles Refinery	Duo-Sol Furnace N-2B	September 2005
Lake Charles Refinery	Duo-Sol Furnace N-2C	September 2005
Lake Charles Refinery	Duo-Sol Furnace S-1	September 2005
Lake Charles Refinery	Duo-Sol Furnace S-2	September 2005
Lake Charles Refinery	Duo-Sol Furnace P-2	September 2005
Lake Charles Refinery	Furfural Furnace BA-1,2A&2B	September 2005
Lake Charles Refinery	Furfural Furnace BA-3	September 2005
Lake Charles Refinery	MEK-1 Furnace BA-1 & 2	September 2005
Lake Charles Refinery	MEK-2 Furnace BA-1 & 2	September 2005
Lake Charles Refinery	MEK-2 Furnace BA-3	September 2005
Lake Charles Refinery	Lube Vacuum BA-1	AMP by February 2010
Lake Charles Refinery	Lube Vacuum BA-101	AMP by September 2011
Lake Charles Refinery	TAME Hydrogen	Unit Shutdown. If restarted, AMP by startup date.

Plant	Unit	Completion/Submittal Date
Lake Charles Refinery	C Dock Butane Unloading	AMP by December 2005

APPENDIX F

FUEL GAS COMBUSTION DEVICES COMPLIANCE SCHEDULE

Plant	Unit Stream	AMP Submittal Date
Corpus Christi East Refinery	Marine Emission Control	6 months after Date of Entry
Corpus Christi East Refinery	NESHAP FF Incinerator	6 months after Date of Entry
Corpus Christi East Refinery	CPI Vapor Combustor	6 months after Date of Entry
Lemont Refinery	333B-401 Barge Dock Benzene Vapor Combustor	6 months after Date of Entry
Lemont Refinery	335B-1 Fuels Rack Emission Control	6 months after Date of Entry
Lake Charles Refinery	B-700 WWT Combustor	June 2007
Lake Charles Refinery	B-13 A-Dock Vapor Combustor	December 2005
Lake Charles Refinery	B-14 B&C Dock Vapor Combustor	December 2005
Lake Charles Refinery	B-15 D Dock Vapor Combustor	December 2005
Lake Charles Refinery	VCU-01 Fuel Loading Rack Combustor	December 2005
Paulsboro Refinery	Marine Emission Combustor	August 2008

APPENDIX G

**NSPS SUBPART J COMPLIANCE SCHEDULE FOR
NSPS FLARING DEVICES**

Plant	Flare	Completion /Submittal Date
Corpus Christi East Refinery	Cumene Flare	December 2007
Corpus Christi East Refinery	Fluor Flare	December 2007
Corpus Christi East Refinery	Acid Gas Flare	AMP by 6 months after Date of Entry
Corpus Christi East Refinery	SWS Flare	AMP by 6 months after Date of Entry
Corpus Christi West Refinery	Flare (*)	December 2006
Corpus Christi West Refinery	Acid Gas Flare	AMP by 6 months after Date of Entry
Corpus Christi West Refinery	SWS Flare	AMP by 6 months after Date of Entry
Lemont Refinery	844C-1 North Plant Flare	Date of Entry
Lemont Refinery	844C-2 South Plant Block 2 Flare (*)	Date of Entry
Lemont Refinery	844C-3 South Plant Block 3 Flare (*)	Date of Entry
Lemont Refinery	844C-4 Needle Coker Flare(*)	Date of Entry
Lemont Refinery	844C-5 Alky Flare	AMP by 6 months after Date of Entry
Lake Charles Refinery	327B-11 Flare C-Ref/CK II(*)	September 2010
Lake Charles Refinery	320B-12 Flare Unicracker	February 2010
Lake Charles Refinery	399B-16 Flare CFH	December 2008
Lake Charles Refinery	360CB-701 (CB-11) PFU	AMP by December 2005
Lake Charles Refinery	CA1001 CLAW	AMP by June 2007
Lake Charles Refinery	B-104 COP/TIERII	December 2011
Paulsboro Refinery	Flare	AMP by August 2006

(*) Identifies flares for which CITGO will install equipment to minimize hydrocarbon flaring from coker blowdown cycles under Paragraph 94.

APPENDIX H

PREDICTIVE EMISSIONS MONITORING SYSTEMS FOR HEATERS AND BOILERS WITH CAPACITIES BETWEEN 150 AND 100 mmBTU/HR

A Predictive Emissions Monitoring Systems ("PEMS") is a mathematical model that predicts the gas concentration of NO_x in the stack based on a set of operating data. Consistent with the CEMS data frequency requirements of 40 C.F.R. Part 60, the PEMS shall calculate a pound per million BTU value at least once every 15 minutes, and all of the data produced in a calendar hour shall be averaged to produce a calendar hourly average value in pounds per million BTU.

The types of information needed for a PEMS are described below. The list of instruments and data sources shown below represent an ideal case. However at a minimum, each PEMS shall include continuous monitoring for at least items 3-5 below. COPC will identify and use existing instruments and refinery data sources to provide sufficient data for the development and implementation of the PEMS.

Instrumentation:

1. Absolute Humidity reading (one instrument per refinery, if available)
2. Fuel Density, Composition and/or specific gravity - On line readings (it may be possible if the fuel gas does not vary widely, that a grab sample and analysis may be substituted)
3. Fuel flow rate
4. Firebox temperature
5. Percent excess oxygen

6. Airflow to the firebox (if known or possibly estimated)
7. Process variable data - steam flow rate, temperature and pressure - process stream flow rate, temperature & pressure, etc.

Computers & Software:

Relevant data will be collected and stored electronically, using computers and software.

The hardware and software specifications will be specified in the source-specific PEMS.

Calibration and Setup:

1. Data will be collected for a period of 7 to 10 days of all the data that is to be used to construct the mathematical model. The data will be collected over an operating range that represents 80% to 100% of the normal operating range of the heater/boiler;
2. A "Validation" analysis shall be conducted to make sure the system is collecting data properly;
3. Stack Testing to develop the actual emissions data for comparison to the collected parameter data; and
4. Development of the mathematical models and installation of the model into the computer.

The elements of a monitoring protocol for a PEMS will include:

1. Applicability
 - a. Identify source name, location, and emission unit number(s);
 - b. Provide expected dates of monitor compliance demonstration testing.
2. Source Description

- a. Provide a simplified block flow diagram with parameter monitoring points and emission sampling points identified (e.g., sampling ports in the stack);
- b. Provide a discussion of process or equipment operations that are known to significantly affect emissions or monitoring procedures (e.g., batch operations, plant schedules, product changes).

3. Control Equipment Description

- a. Provide a simplified block flow diagram with parameter monitoring points and emission sampling points identified (e.g., sampling ports in the stack);
- b. List monitored operating parameters and normal operating ranges;
- c. Provide a discussion of operating procedures that are known to significantly affect emissions (e.g., catalytic bed replacement schedules).

4. Monitoring System Design

- a. Install, calibrate, operate, and maintain a continuous PEMS;
- b. Provide a general description of the software and hardware components of the PEMS, including manufacturer, type of computer, name(s) of software product(s), monitoring technique (e.g., method of emission correlation).
Manufacturer literature and other similar information shall also be submitted, as appropriate;
- c. List all elements used in the PEMS to be measured (e.g., pollutant(s), other exhaust constituent(s) such as O₂ for correction purposes, process parameter(s), and/or emission control device parameter(s));

- d. List all measurement or sampling locations (e.g., vent or stack location, process parameter measurement location, fuel sampling location, work stations);
 - e. Provide a simplified block flow diagram of the monitoring system overlaying process or control device diagram (could be included in Source Description and Control Equipment Description);
 - f. Provide a description of sensors and analytical devices (e.g., thermocouple for temperature, pressure diaphragm for flow rate);
 - g. Provide a description of the data acquisition and handling system operation including sample calculations (e.g., parameters to be recorded, frequency of measurement, data averaging time, reporting units, recording process);
 - h. Provide checklists, data sheets, and report format as necessary for compliance determination (e.g., forms for record keeping).
5. Support Testing and Data for Protocol Design
- a. Provide a description of field and/or laboratory testing conducted in developing the correlation (e.g., measurement interference check, parameter/emission correlation test plan, instrument range calibrations);
 - b. Provide graphs showing the correlation, and supporting data (e.g., correlation test results, predicted versus measured plots, sensitivity plots, computer modeling development data).
6. Initial Verification Test Procedures

- a. Perform an initial relative accuracy test (RA test) to verify the performance of the PEMS for the equipment's operating range. The PEMS must meet the relative accuracy requirement of the applicable Performance Specification in 40 C.F.R. Part 60, Appendix B. The test shall utilize the test methods of 40 CFR Part 60, Appendix A;
- b. Identify the most significant independently modifiable parameter affecting the emissions. Within the limits of safe unit operation, and typical of the anticipated range of operation, test the selected parameter for three RA test data sets at the low range, three at the normal operating range and three at the high operating range of that parameter, for a total of nine RA test data sets. Each RA test data set should be between 21 and 60 minutes in duration;
- c. Maintain a log or sampling report for each required stack test listing the emission rate;
- d. Demonstrate the ability of the PEMS to detect excessive sensor failure modes that would adversely affect PEMS emission determination. These failure modes include gross sensor failure or sensor drift;
- e. Demonstrate the ability to detect sensor failures that would cause the PEMS emissions determination to drift significantly from the original PEMS value;
- f. The PEMS may use calculated sensor values based upon the mathematical relationships established with the other sensors used in the PEMS.

Establish and demonstrate the number and combination of calculated sensor values which would cause PEMS emission determination to drift significantly from the original PEMS value.

7. Quality Assurance Plan

- a. Provide a list of the input parameters to the PEMS (e.g., transducers, sensors, gas chromatograph, periodic laboratory analysis), and a description of the sensor validation procedure (e.g., manual or automatic check);
- b. Provide a description of routine control checks to be performed during operating periods (e.g., preventive maintenance schedule, daily manual or automatic sensor drift determinations, periodic instrument calibrations);
- c. Provide minimum data availability requirements and procedures for supplying missing data (including specifications for equipment outages for QA/QC checks);
- d. List corrective action triggers (e.g., response time deterioration limit on pressure sensor, use of statistical process control (SPC) determinations of problems, sensor validation alarms);
- e. List trouble-shooting procedures and potential corrective actions;
- f. Provide an inventory of replacement and repair supplies for the sensors;
- g. Specify, for each input parameter to the PEMS, the drift criteria for excessive error (e.g., the drift limit of each input sensor that would cause the PEMS to exceed relative accuracy requirements);
- h. Conduct a quarterly electronic data accuracy assessment tests of the PEMS;

- i. Conduct semiannual RA tests of the PEMS. Annual RA tests may be conducted if the most recent RA test result is less than or equal to 7.5%.
Identify the most significant independently modifiable parameter affecting the emissions. Within the limits of safe unit operation and typical of the anticipated range of operation, test the selected parameter for three RA test data pairs at the low range, three at the normal operating range, and three at the high operating range of that parameter for a total of nine RA test data sets. Each RA test data set should be between 21 and 60 minutes in duration.

8. PEMS Tuning

- a. Perform tuning of the PEMS provided that the fundamental mathematical relationships in the PEMS model are not changed.
- b. Perform tuning of the PEMS in case of sensor recalibration or sensor replacement provided that the fundamental mathematical relationships in the PEMS model are not changed.

APPENDIX I

DATED: DECEMBER 7, 1999; SIGNED: JOHN B. RASNIC

Phillip E. Guillemette
Director of Environmental Affairs
Koch Refining Company LP
P.O. Box 64596
Saint Paul, Minnesota 55164-0596

Dear Mr. Guillemette:

This is in response to your August 14, 1998, and January 6, 1999, letters to Administrator Carol Browner, and your July 9, 1999, supplemental submittal. Please find enclosed, our December 2, 1999, response addressing applicability issues of the New Source Performance Standards NSPS Subpart J to refinery fuel gases and fuel gas combustion devices. Also enclosed is our general "Alternative Monitoring Plan for NSPS Subpart J Refinery Fuel Gases" addressing your request for approval of an alternative plan to continuous monitoring of refinery fuel gases.

While your July 9, 1999, supplemental submittal and the September 3, 1999, letter from Mr. James Mahoney, your Senior Vice President of Operations, request that we approve a proposed flare management policy, we are unable to do so at this time. We continue to review the issue. We appreciate your willingness to meet with us to answer questions on these difficult issues, and hope we can work out a resolution that provides clarification for what the Environmental Protection Agency considers to be "good air pollution control practice for minimizing emissions" under NSPS Subpart J for flare systems. As we continue to work on an agreement for a flaring policy, based on our past discussions with representatives from Koch, we believe that many of your current and planned practices to minimize flaring events (assuming proper documentation of those practices) are elements of "good air pollution control" and provide adequate protection of human health and the environment.

I trust that the enclosed information will be useful to you. If you have any questions, please feel free to contact Tom Ripp of my staff at (202) 564-7003.

Sincerely,

s/ JOHN B. RASNIC

John B. Rasnic, Director
Manufacturing, Energy and Transportation Division
Office of Compliance

Enclosures

cc: James Mahoney, Koch
Preparedby:t.ripp:mlw:12/3/99:2:30 PM:2pp:564-7003:2223A:kochco~1.wpd

DATED: DECEMBER 2, 1999; SIGNED: KEN GIGLIELLO for

Phillip E. Guillemette
Director of Environmental Affairs
Koch Refining Company LP
P.O. Box 64596
Saint Paul, Minnesota 55164-0596

Dear Mr. Guillemette:

This is in response to your August 14, 1998, and January 6, 1999, letters to Administrator Browner. Koch Refining Company LP (Koch) seeks clarification from the Environmental Protection Agency (EPA) regarding the applicability of New Source Performance Standard Subpart J (NSPS Subpart J) to: fuel gas combustion devices (FGCDs) and fuel gases; "process upset" conditions; and to certain identified gas streams at its Rosemount, Minnesota refinery. Although you requested that EPA review and revise NSPS Subpart J in your August 14, 1998, letter, it is our current understanding that you are not requesting that NSPS Subpart J be reviewed/revised as part of a response to your letters.

You write that NSPS Subpart J is, in part, intended to reduce sulfur emissions from gases generated as a byproduct of the refining process that are used as fuel in a refinery's heaters and boilers. To accomplish this, NSPS Subpart J imposes monitoring requirements and limits for certain fuel gas streams that are combusted in refinery FGCDs. You assert that "fuel gas" and "FGCD" are vaguely defined, and it is often unclear as to what types of units and streams are covered under the standard. We disagree with your characterization that "fuel gas" and "FGCD" are not clearly defined. The definitions are purposefully broad, and the exemptions are specific. We also disagree with your characterizations that the rule is limited to only refinery generated gases burned as fuel in refinery process heaters and boilers. The rule clearly includes routine combustion of refinery gases in flares and other waste gas disposal devices.

In your letter, you develop a position on exemptions from NSPS Subpart J based on the commendable use of a flare gas recovery system. You describe your refinery flare gas recovery system, and state that:

. . . [a]s designed, the flare gas recovery system has sufficient capacity to recover gases that are routed to the system under normal operating conditions Under process upset conditions, the flare gas recovery system's capacity may be exceeded and excess gases are routed to the flare for combustion

Prepared by: t.ripp:mlw:9/20/99:2:14 PM:pp:564-7003:2223A:koch5.wpd

Because you believe that your refinery gases are routed to the flare only as a result of process upsets, you believe that the flaring of those gases are not subject to NSPS Subpart J. We do not agree that all of the events you describe as "process upset conditions" meet the regulatory definition of malfunction or the interpretation of "upset", and, therefore, may not be qualified for exemption from NSPS Subpart J. In addition, we note that any malfunction or upset involving combustion of process upset gas in an NSPS-affected FGCD would still be subject to NSPS Subpart A (General Provisions) §60.11(d) obligations.

Your August 14, 1998, letter focuses on three areas:

- How NSPS Subpart J applies to FGCDs and fuel gases;
- How the process upset gas exemption applies;
- How NSPS Subpart J applies to the 26 miscellaneous gas streams.

Our response addresses those issues in order.

How NSPS Subpart J Applies to FGCDs and Fuel Gases

The provisions of NSPS Subpart J are, in part, applicable to affected FGCDs. To control sulfur oxide (SO_x) emissions to the atmosphere from affected FGCDs, NSPS Subpart J §60.104(a)(1) limits the amount of hydrogen sulfide (H_2S) allowed in the fuel gas burned in those devices. Except for fuel gas released to a flare as a result of relief valve leakage or other emergency malfunctions, you must not burn fuel gas containing greater than 230 mg/dscm of H_2S in any affected FGCD. Additionally, the combustion of a process upset gas in a FGCD is exempt from the H_2S limit. The combustion/flaring of those exempted gases in an NSPS-affected FGCD is still subject to §60.11(d) of the General Provisions as described later.

NSPS Subpart J §60.104(a)(1) applies to gas combustion devices, if the following are true:

1) The gas is a "fuel gas" [§60.101(d)]:

. . . any gas which is generated at a petroleum refinery and which is combusted. Fuel gas also includes natural gas when the natural gas is combined and combusted in any proportion with a gas generated at a refinery. Fuel gas does not include gases generated by catalytic cracking unit catalyst regenerators and fluid coking burners.

2) The fuel gas is combusted in a "FGCD" [§60.101(g)]:

. . . any equipment, such as process heaters, boilers and flares used to combust fuel gas, except facilities in which gases are combusted to produce sulfur or sulfuric acid.

3) The FGCD is an "affected FGCD". An affected FGCD is any FGCD for which construction or modification commenced after June 11, 1973. §60.100(b)

Additionally, when determining the applicability of NSPS Subpart J to any particular combination of combustion device and gas stream, the following general concepts apply:

- Unlike the definition of process upset gas, the definition of fuel gas does not require that the gas be generated by a "refinery process unit", it must merely be generated at the refinery;
- There is no general exemption for gas streams with low sulfur content;
- There is no general exemption for low volume or intermittent gas streams;
- A FGCD need not generate a product to be regulated. Flares do not generate products or energy that are recovered for use, but they are clearly FGCDs since they are specifically named in the definition.

Your refinery flares (constructed after June 11, 1973) are affected FGCDs as defined by NSPS Subpart J. When the capacity of your refinery flare gas recovery system is exceeded as the result of normal operations (not malfunctions), NSPS Subpart J for FGCDs applies to those NSPS refinery flares.

For any fuel gas stream subject to NSPS Subpart J, you may petition for alternative monitoring under the General Provisions at §60.13(i). For EPA to approve alternative monitoring, you must submit sufficient information to show that your alternative monitoring plan will yield similar results to the required monitoring under NSPS Subpart J.

How the Process Upset Gas Exemption Applies

As mentioned above, §60.104(a)(1) exempts the combustion in a FGCD of process upset gases and exempts the combustion in a flare of fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunction. Not all of the events you describe as "process upset conditions" meet the qualifications for exemption from NSPS Subpart J. Therefore, the 26 gas streams do not receive a blanket exemption from the regulation. Some of the gases generated under Koch's described events are not gases generated as a result of upsets, but are generated as a result of normal operations. Additionally, not all of your process upsets

result in flaring.

Process upset gas is defined at §60.101(e) as:

. . . any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction.

Malfunction is defined in the General Provisions at §60.2 as:

. . . any sudden, infrequent, and not reasonably preventable failure of air pollution control equipment, process equipment, or a process to operate in a normal or usual manner. Failures that are caused in part by poor maintenance or careless operation are not malfunctions.

Upset is not defined in NSPS Subpart J or in the General Provisions. However, in EPA's 1973 Background Information for Proposed New Source Performance Standards for Petroleum Refineries, PB-221 736 (1973 BID), page 25, EPA writes that the proposed standard does not apply to extraordinary situations, such as emergency gas releases. In EPA's 1974 Background Information for New Source Performance Standards for Petroleum Refineries, PB-231 601 (1974 BID), page 20, EPA further explained the statement in the 1973 BID that:

Because the frequency of process upsets and the volumes of gases which must be disposed of are highly unpredictable, it is not feasible to design or operate a gas treating facility that would prevent sulfur dioxide emissions from flare systems in these situations. A facility designed to remove hydrogen sulfide from all process upset gases prior to combustion would have to be designed to handle the immediate release of gases from all process units if each unit experienced the worst possible upset or malfunction at the same time. The cost of such a large gas treatment facility would impose a severe and unreasonable economic burden upon a refinery.

From the language in the 1974 BID, it is clear that a facility does not have to be designed to treat and dispose of gases produced in a worst case scenario at a facility. However, it is clear that more frequent and predictable process events (which Koch would describe as "upsets", but which do not meet the interpretation for upsets) are subject to the standard, and that it is not unreasonable for the facility to have sufficient capacity to handle these routine process events.

In a similar issue, EPA successfully argued in a case before an Administrative Law Judge (ALJ), that the term "system breakdown" (which is used in 40 CFR §60.13(e), but is undefined) was akin to a malfunction as defined in the General Provisions at §60.2. In the March 9, 1995, decision (see Enclosure 1), the ALJ wrote that:

While the actual words "system breakdown" do not appear here [in the definition of malfunction], this definition incorporates analogous phrases Thus using the definition of malfunction as a guide, a system breakdown would constitute something sudden and unforeseen Accordingly, it is found that a system breakdown requires there to be an occurrence which is unforeseen, sudden and unavoidable.

The same logic that went into the ALJ's decision applies here; the exemption was intended for infrequent and unpredictable events, thus, "upset" is analogous to malfunction.

Therefore, the malfunction/upset exemption under NSPS Subpart J applies only to extraordinary, infrequent, and not reasonably preventable upsets. Additionally, the malfunction/upset cannot be the result of poor maintenance or careless operations. Once you determine the cause of a malfunction/upset, you should work to correct the root cause in order to prevent it from occurring again. Each time that is done, malfunctions/upsets should become less frequent.

Process upset gases exempted under NSPS Subpart J are still required to comply with the good air pollution control practices as required under §60.11(d).

At all times, including periods of start-up, shut-down, and malfunction, owners and operators shall, to the extent practicable, maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions

How NSPS Subpart J Applies to the 26 Specific Gas Streams

(Unless stated otherwise, it is assumed that all of the following gas streams are generated "at" the refinery and are combusted. The general concepts identified on page 2 of this letter should be incorporated into EPA's responses when those concepts address the position(s) presented by Koch for a particular gas stream.)

A. Commercial Grade Natural Gas

Koch's position:

NSPS Subpart J is inapplicable because this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

Refinery generated, commercial grade, natural gas is subject to NSPS Subpart J if it is combusted in an affected FGCD.

Refinery generated, commercial grade, natural gas meets the definition of fuel gas.

Note: Commercial grade natural gas purchased from an outside source is not generated "at" the refinery and is not, itself, a fuel gas. EPA has previously determined that an NSPS affected gas combustion device is not required to have an installed SO₂ or H₂S CEM if that device has been confirmed to not burn refinery fuel gas, in any mixture and at any time (e.g., To be exempt from NSPS Subpart J, a combustion device must be fired only with purchased gas from a dedicated line, and must be isolated from the refinery's fuel gas system). See the December 4, 1991, memorandum from John B. Rasnic. (Enclosure 2)

B. Hydrogen Plant PSA Purge Gas

Koch's position:

NSPS Subpart J is inapplicable because this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

The combustion of Hydrogen Plant PSA Purge gas in the #2 Hydrogen Plant process heater is subject to NSPS Subpart J.

1) Hydrogen Plant PSA Purge Gas meets the definition of fuel gas.

2) The Hydrogen purge gas is burned in the #2 Hydrogen Plant process heater. The #2 Hydrogen Plant process heater meets the definition of FGCD.

3) The #2 Hydrogen Plant process heater is an "affected" FGCD.

C. Commercial Grade Propane (LPG)

Koch's position:

NSPS Subpart J is inapplicable because this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

Refinery generated, commercial grade, propane gas is subject to NSPS Subpart J if it is combusted in an affected FGCD.

Refinery generated, commercial grade, propane gas meets the definition of fuel gas.

Note: Commercial grade propane gas purchased from an outside source is not generated "at" the refinery and is not, itself, a fuel gas. To be exempt from NSPS Subpart J, a combustion device must be fired only with purchased gas from a dedicated line, and must be isolated from the refinery's fuel gas system.

D. Commercial Grade Hydrogen**Koch's position:**

NSPS Subpart J is inapplicable because this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

Refinery generated, commercial grade, hydrogen is subject to NSPS Subpart J if it is combusted in an affected FGCD.

Refinery generated, commercial grade, hydrogen meets the definition of fuel gas.

Commercial grade hydrogen purchased from an outside source is not generated "at" the refinery and is not, itself, a fuel gas. To be exempt from NSPS Subpart J, a combustion device must be fired only with purchased gas from a dedicated line, and must be isolated from the refinery's fuel gas system.

E. Delayed Coker Blowdown**Koch's Position:**

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

EPA's position:

Any coker blowdown gas generated as a normal part of operations that is directed to the refinery flares, is subject to NSPS Subpart J.

- 1) Vapor from the delayed coker blowdown process meets the definition of fuel gas.

Coker blowdown vapor is generated as a normal part of operations, and not the result of a process upset or malfunction. Nor is it exempt because it is generated during a "shutdown" since the coking process has not shutdown. Rather, the stream to the cokers is merely shifted from one coking drum to another to maintain continuous operation of the coker unit.

- 2) The hydrocarbon vapors from the blowdown process are directed to your flare gas recovery system. When the refinery flare gas recovery system's capacity is exceeded, the excess gas flared.

- 3) As described earlier, the refinery flares are affected FGCDs.

F. Rail Loading Rack Thermal Oxidizer**Koch's Position:**

NSPS Subpart J is inapplicable because the thermal oxidizer is not a "FGCD" subject to Subpart J, and vapors routed to the thermal oxidizer are low in sulfur and are not a "fuel gas" generated by a refinery process.

EPA's response:

Vapor from loading rack operations is subject to NSPS Subpart J if it is combusted in an affected FGCD.

- 1) Vapors from loading racks located at the refinery meet the definition of fuel gas.
- 2) Although the oxidizer may be added as a control device under the refinery MACT, it still meets the definition of FGCD under NSPS Subpart J and is subject to NSPS Subpart J. The refinery MACT (40 CFR Part 63 Subpart CC) is designed to limit the

release of hazardous air pollutants (HAPs) and not SO_x from petroleum refineries. Combustion of those HAPs is not the only control option available for compliance with the refinery MACT. Other compliance alternatives under the refinery MACT that do not involve combustion will not trigger the NSPS Subpart J requirements.

G. Soil Vapor Extraction Thermal Oxidizer

Koch's Position:

NSPS Subpart J is inapplicable to this stream because vapors recovered from soil remediation are not a "fuel gas", and the thermal oxidizer is not a "FGCD".

EPA's response:

Extracted soil vapor is subject to NSPS Subpart J if it is combusted in an affected FGCD.

- 1) Vapors extracted from the soil within the refinery meet the definition of fuel gas.
- 2) The thermal oxidizer is a FGCD since it combusts a fuel gas.

H. Wastewater Treatment Plant Thermal Oxidizer

Koch's Position:

NSPS Subpart J is inapplicable because vapors from the wastewater treatment plant are not a "fuel gas", and the thermal oxidizer is not a "FGCD".

EPA's response:

Vapor from the refinery's WWTP is subject to NSPS Subpart J if it is combusted in an affected FGCD.

- 1) The refinery is operating a wastewater treatment plant (WWTP) at the refinery. The vapors collected from the WWTP meet the definition of fuel gas. Other regulations (i.e., NSPS QQQ) that may cover vapors from the WWTP do not specifically exempt the WWTP vapors from applicability under NSPS Subpart J.
- 2) Although a thermal oxidizer may be a control device for other regulations (i.e., NSPS QQQ), it meets the definition of FGCD for NSPS Subpart J.

Note: Your claim that EPA's approval of the State Implementation Plan (SIP) order for the Dakota County/Pine Bend Area of Air Quality Control Region 131 is evidence of EPA's determination that NSPS Subpart J is inapplicable to this gas stream is not correct. In approving the SIP order, the gas stream was not characterized as being combusted in an NSPS Subpart J applicable fuel gas combustion device, and EPA was not asked to make a determination of the applicability of NSPS Subpart J to any gas streams or affected fuel gas combustion devices. It merely represents EPA's approval of the State's requirements. Additionally, EPA included language in Amendment Three to the Findings and Order by Stipulation in paragraphs D and H indicating that the order does not relieve Koch of the obligation to comply with all applicable laws and regulations, and that those requirements may be more stringent. The relevant pages of Amendment Three are included as Enclosure 3.

I. Merox Off-Gas (34-H-3 Thermal Oxidizer)

Koch's Position:

NSPS Subpart J is inapplicable to this stream because the thermal oxidizer was constructed prior to June 11, 1973, and has not been modified or reconstructed.

EPA's response:

Any fuel gas combusted in the 34-H-3 thermal oxidizer is not subject to NSPS Subpart J §60.104(a)(1) as long as the thermal oxidizer is not modified or reconstructed.

- 1) Merox caustic regenerator vent gas, vapors from spent caustic storage tanks, sour water flash drums, and fresh amine storage tanks meet the definition of fuel gas.
- 2) The 34-H-3 thermal oxidizer meets the definition of FGCD.
- 3) Based on your statement that the 34-H-3 thermal oxidizer was constructed before June 11, 1973, it is not an "affected" FGCD unless it has since been modified or reconstructed.

J. Caustic Neutralizer Off-Gas

Koch's Position:

NSPS Subpart J is inapplicable to the stream because the CO boiler was constructed prior to June 11, 1973 and has not been modified or reconstructed.

EPA's response:

Any gas combusted in the CO boiler is not subject to NSPS Subpart J §60.104(a)(1) as long as the CO boiler is not modified or reconstructed.

- 1) The off-gas from the spent caustic neutralizers meets the definition of fuel gas.
- 2) The spent caustic off-gas is routed to the CO boiler. The CO boiler meets the definition of FGCD.
- 3) Based on your statement that the CO boiler was constructed before June 11, 1973, and has not been modified or reconstructed, it is not an "affected" FGCD.

K. Reformer Catalyst Regeneration Streams**Koch's Position:**

NSPS Subpart J is inapplicable because these streams are inherently low in sulfur, and they fall under the Subpart J exemption for process upset gas.

EPA's response:

Any regeneration gas generated as a normal part of operations that is directed to the refinery flares, is subject to NSPS Subpart J. Additionally, lock hopper gas that is not directed to the refinery flare gas recovery system but is directed to a refinery heater is subject to NSPS Subpart J if the refinery heater is an affected FGCD.

- 1) Reformer catalyst regeneration gas streams meet the definition of fuel gas.

Gas produced during the routine switching of reformer reactors, as described by Koch, does not meet the process upset gas definition because the gas is generated as a normal part of operations. Nor is it exempt because it is generated during a "shutdown" since the reformer process has not shutdown. Rather, operations merely shift from one reactor to another so that spent catalyst may be regenerated while the reformer unit continues operation.

- 2) Reformer catalyst regeneration gas produced during the switching process is directed to your flare gas recovery system or, for final lock hopper depressurization, to a refinery heater. When the refinery flare gas recovery system's capacity is exceeded, the excess gas flared.
- 3) As described earlier, the refinery flares are affected FGCDs.

L. Vacuum Unit Off-Gas

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

According to your description, equipment leaks may allow air to enter the process creating a potential for the formation of combustible mixtures. Under normal operation, vacuum gases are routed to the fuel gas system. The only time vacuum unit off-gas potentially may be combusted in a fuel gas combustion device is when there has been a process upset as defined under NSPS Subpart J §60.101(e).

EPA's response:

Vacuum unit off-gas that meets the definition of process upset gas is subject to NSPS Subpart A §60.11(d).

- 1) Vacuum unit off-gas meets the definition of fuel gas.
- 2) Any gas generated by a petroleum refinery process unit as a result of start-up, shut-down, upset or malfunction is a process upset gas.
- 3) Vacuum unit off-gas generated during periods of a malfunction of the vacuum distillation column meets the definition of process upset gas.

Additionally, in our August 10, 1999, meeting, we discussed the effect of shut-downs of Koch's low pressure off-gas recovery compressor and flare gas recovery compressor. Koch has a compressor system designed to recover discharges (off-gas) from the vacuum generating equipment. The recovered off-gas is normally routed to the refinery fuel gas recovery system for H₂S removal. In the event of an off-gas recovery compressor shut-down, the off-gas is routed to the refinery flare gas recovery system and is not sent to the flare. Only when both compressors malfunction would the gas be routed to the flare. If both compressors are down at the same time due to malfunctions as defined under NSPS Subpart A §60.2, then the vacuum unit off-gas would meet the exemption under NSPS Subpart J §104(a)(1) for other emergency malfunctions. Off-gases exempted from the emission requirements under NSPS Subpart J §60.104(a)(1) are still subject to NSPS Subpart A §60.11(d).

M. Slop Oil Flash Drum**Koch's Position:**

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

EPA's response:

Any vapor from the slop oil process which is generated as a normal part of operations that is directed to the refinery flares, is subject to NSPS Subpart J.

1) In general, vapors generated by the slop oil process at Koch meet the definition of fuel gas. Sending off-specification products to the slop oil system does not qualify as a process upset.

2) When the refinery's flare gas recovery's system is exceeded, excess gas is sent to the refinery's flares. Process upsets/malfunctions are not the only reasons that Koch's flare gas recovery system's capacity may be exceeded. The refinery's flare gas recovery system may be exceeded as a result of normal operations (e.g., delayed coker blowdown).

3) As described earlier, the refinery flares are affected FGCDs.

N. Alkylation Unit Acid Neutralization Pit Off-Gas**Koch's Position:**

NSPS Subpart J is inapplicable to this stream because the sulfuric acid alkylation units is not a "FGCD", and this stream falls under the Subpart J exemption for process upset gas.

EPA's response:

If the off-gas from the alkylation unit acid neutralization is not combusted, NSPS Subpart J is not applicable. Only gases generated and combusted at the refinery (including purchased gas that is mixed with fuel gas) meet the definition of fuel gas.

O. Flare Pilot and Purge**Koch's Position:**

NSPS Subpart J is inapplicable because pilot and purge gas is not a "fuel gas", and this stream is inherently low in sulfur and has no potential for significant sulfur dioxide emissions.

EPA's response:

As identified in your letter, EPA issued a determination (March 22, 1977) regarding refinery pilot lights. We reaffirm our earlier position that NSPS Subpart J is inapplicable to refinery pilot lights. Since a pilot light ensures that a combustion device will operate properly, the pilot light, by itself, is not the combustion device.

P. Miscellaneous Process Streams Routed to Flare Gas Recovery System

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

EPA's response:

Any vapors from the refinery's miscellaneous process streams generated as a normal part of operations that is directed to the refinery flares, is subject to NSPS Subpart J.

- 1) Vapors from miscellaneous process streams meet the definition of fuel gas because they are not specifically exempted from the definition of fuel gas.
- 2) When the refinery's flare gas recovery system is exceeded, excess gas is sent to the refinery's flares. Process upsets/malfunctions are not the only reasons that Koch's flare gas recovery system's capacity may be exceeded. The refinery's flare gas recovery system may be exceeded as a result of normal operations.
- 3) As described earlier, the refinery flares are affected FGCDs.

Q. Butane Storage Tank 517 Thermal Oxidizer

Koch's Position:

NSPS Subpart J is inapplicable because this stream is not generated by a Refinery process, it is inherently low in sulfur, and it is subject to the Subpart J exemption for process upsets. To date, the thermal oxidizer has never been used.

EPA's response:

Butane vapors generated as a result of a refrigerator system malfunction are not subject to NSPS Subpart J control requirements, but are subject to NSPS Subpart A §60.11(d).

- 1) Butane vapors meet the definition of fuel gas.
- 2) If butane vapors are formed as a result of refrigeration system malfunction, the vapors are routed to tank 517 thermal oxidizer.
- 3) NSPS Subpart J §61.104(a)(1) exempts the combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunction.

R. FCC Catalyst Regenerator Off-Gas

Koch's Position:

NSPS Subpart J is inapplicable because this stream is subject to the express exemption for catalytic cracking unit catalyst regenerators.

EPA's response:

FCC catalyst regenerator off-gas does not meet the definition of fuel gas and, therefore, is exempt from NSPS Subpart J §60.104(a)(1).

S. MEA and MDEA Regenerator Off-Gas

Koch's Position:

NSPS Subpart J fuel gas requirements are inapplicable because this stream falls under the exemption for facilities that are part of the sulfur production process.

EPA's response:

Sending these streams to the sulfur recovery unit (SRU) does not subject them to the NSPS Subpart J standard for the combustion of a fuel gas in a FGCD.

- 1) MEA and MDEA regenerator off-gas streams meet the definition of fuel gas.
- 2) Because these recycled streams are sent to the front of the SRU, and the SRU is a facility in which gases are combusted to produce sulfur or sulfuric acid, these streams are not being combusted in a FGCD.

T. Sour Water Tank Purge Gas**Koch's Position:**

This stream falls under the Subpart J exemption for sulfur production facilities and has previously been determined by USEPA to be not subject to NSPS Subpart J fuel gas requirements.

EPA's response:

If the standby incinerator was constructed or modified after June 11, 1973, it is an affected FGCD and the combustion of sour water tank purge gas is subject to NSPS Subpart J.

- 1) Sour water tank purge gas meets the definition of fuel gas.
- 2) Sour water tanks store process water from various refinery process units. These tanks are not part of the SRU since they are not part of the unit that recovers sulfur from H_2S by a vapor-phase catalytic reaction of SO_2 and H_2S .
- 3) At Koch's facility, the sour water tank purge gas is sent directly to a SRU standby incinerator (affected FGCD) for thermal oxidation without going through the SRU.

Note: Again, you claim that EPA's approval of the State Implementation Plan (SIP) order for the Dakota County/Pine Bend Area of Air Quality Control Region 131 is evidence of EPA's determination that NSPS Subpart J is inapplicable to this gas stream. For the reasons stated in our response to stream H, your belief is not correct.

U. Sour Water Stripper Overhead Gas**Koch's Position:**

NSPS Subpart J fuel gas requirements are inapplicable because this stream is part of the sulfur production process and falls under the Subpart J exemption for process upset gas.

EPA's response:

Introducing these streams into the SRU does not subject them to NSPS Subpart J requirements applicable to the combustion of a fuel gas in a FGCD.

- 1) Sour water stripper overhead gas meets the definition of fuel gas.
- 2) Sour water strippers are not part of the SRU since they are not part of the unit that recovers sulfur from H_2S by a vapor-phase catalytic reaction of SO_2 and H_2S .

3) Koch sends the sour water stripper overhead gas to the SRU. The SRU is not a FGCD because it is a facility in which gases are combusted to produce sulfur or sulfuric acid.

Note: Koch indicates that this gas may be routed to a FGCD (bypassing the SRU) during periods of start-up, shut-down or malfunction of the SRU. It maintains that such combustion is not subject to Subpart J's sulfur oxide standard because these gases are exempt process upset gases.

Exemptions from rules of general applicability are to be construed narrowly. Nonetheless, EPA recognizes that there are certain limited circumstances under which normal processes may be bypassed because upset conditions exist in some upstream process unit (e.g., if upstream gas quality will cause a malfunction in a downstream unit, the gas is diverted to a flare instead).

It is the refinery's burden to demonstrate that a malfunction has occurred each time a downstream unit is bypassed (or otherwise demonstrate that its actions are exempt from regulation). EPA notes that a malfunction must be infrequent, not reasonably preventable and not attributable to poor maintenance or careless operation. For example, a "malfunction" caused by the same or similar conditions as had occurred previously will lose its exempt character and be subject to all applicable standards and requirements.

Periods of routine or periodic maintenance to downstream units are not malfunctions at either the upstream or the downstream unit. Gases generated in the upstream units are not then process upset gases, their combustion is subject fully to applicable NSPS Subpart J standards and the bypassing (without proper controls) of a downstream unit that is undergoing routine or periodic maintenance would not be permitted.

If the capacity of the SRU is exceeded due to process upset gases, such gases may be flared (but only to the extent attributable to such upset gas). Such instances are also subject to §60.11(d). See discussion above.

V. Ammonia Acid Gas Flare

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas. The acid gas flare is used only for ammonia acid gas that cannot be processed in the SRU due to start-up, shut-down or malfunction.

EPA's response:

Process upset gases are those gases generated by a refinery process unit during periods of start-up, shut-down, upset or malfunction. Such gases are subject to 60.11(d). See discussion above.

- 1) Ammonia acid gas meets the definition of fuel gas.
- 2) Combustion of a fuel gas in a flare constructed or modified after June 11, 1973, is subject to Subpart J standards for sulfur oxides, but combustion of process upset gases is exempt from those standards.

Note: Exemptions from rules of general applicability are to be construed narrowly. Nonetheless, EPA recognizes that there are certain limited circumstances under which normal processes may be bypassed because upset conditions exist in some upstream process unit (e.g., if upstream gas quality will cause a malfunction in a downstream unit, the gas is diverted to a flare instead).

It is the refinery's burden to demonstrate that a malfunction has occurred each time a downstream unit is bypassed (or otherwise demonstrate that its actions are exempt from regulation). EPA notes that a malfunction must be infrequent, not reasonably preventable and not attributable to poor maintenance or careless operation. For example, a "malfunction" caused by the same or similar conditions as had occurred previously will lose its exempt character and be subject to all applicable standards and requirements.

Periods of routine or periodic maintenance to downstream units are not malfunctions at either the upstream or the downstream unit. Gases generated in upstream units are not then process upset gases, their combustion is subject fully to applicable NSPS Subpart J standards and the bypassing of a downstream unit that is undergoing routine or periodic maintenance would not be permitted.

Based on information EPA has, numerous episodes of combustion of ammonia acid gas in a flare subject to NSPS Subpart J suggests that there are operation and maintenance problems with those refinery units generating and/or processing that gas.

W. Sulfur Degassing Off-Gas

Koch's Position:

This stream falls under the Subpart J exemption for sulfur production facilities and has previously been determined by USEPA to be not subject to Subpart J fuel gas requirements.

EPA's response:

The sulfur degassing off-gas is generated within the SRU, it is subject to the requirements of NSPS Subpart J §60.104(a)(2) and is exempt from §60.104(a)(1). Please note that some other sulfur pit degasification processes would not be considered as integral parts of a Claus sulfur recovery plant, as defined, and consequently, their exhaust gases could be subject to §60.104(a)(1).

It is our understanding that Koch uses the Shell sulfur degasification process. This process involves a vapor phase reaction that converts much of the dissolved H₂S into elemental sulfur within the stripping column of the sulfur pit. For purposes of the regulation, this conversion process is equivalent to the Claus process.

It appears, from your May 14, 1999, Generic Tail Gas Treatment Unit (TGTU) Flow Chart, that the sulfur degassing off-gas is generated within the sulfur pit of each SRU and then routed to the emergency bypass incinerator to be combusted. It is combusted along with sour water tank off-gas, fuel gas and any tail gas from the SRU that bypassed the TGTU. That combustion results in an exhaust that is a combination of gases, some subject to §60.104(a)(1) and others to §60.104(a)(2). Accordingly, each stream going to the emergency bypass incinerator must be monitored separately, or the more stringent of the two limits applies (in this case, the FGCD limit). Streams subject to the same standards may be combined and only the combined stream need then be monitored.

Note: Again, you claim that EPA's approval of the State Implementation Plan (SIP) order for the Dakota County/Pine Bend Area of Air Quality Control Region 131 is evidence of EPA's determination that NSPS Subpart J is inapplicable to this gas stream. For the reasons stated in our response to stream H, your belief is not correct.

X. SRU TGTU Process Heater

Koch's Position:

NSPS Subpart J fuel gas requirements are inapplicable because this stream falls under the exemption for facilities in which gases are combusted to produce sulfur.

EPA's response:

NSPS Subpart J §60.104(a)(2) prohibits the discharge of any gases into the atmosphere from any Claus sulfur recovery plant containing excess amounts of SO₂. According to your diagrams, the exhaust from the heater/reactor goes into a liquid-gas H₂S recovery system. The recovered H₂S is then recycled back to the feed line of the SRU. Since the SO₂ is converted into H₂S and is not discharged into the atmosphere, NSPS Subpart J requirements are not applicable to the direct-fired heater on the reducing gas reactor within the TGTU.

Although we agree that this direct fired heater is not subject to NSPS Subpart J §60.104(a)(1) [as discussed above], we do not agree with Koch's interpretation of the heater being exempt because it is part of the sulfur recovery plant. Koch argues that the exemption for sulfur recovery plants applies to this heater. It does not. The heater and reducing gas generator are not in the SRU; the H₂S stream that they generate is desired for improving the efficiency of the SRU, but is not essential for the operation of the SRU; and the recycled H₂S stream would be "fuel gas" if combusted anywhere other than in the SRU or a sulfuric acid plant at the refinery (the two combustion devices exempted from

being "FGCDs").

Y. SRU TGTU Incinerator

Koch's Position:

This unit is subject to, and complies with Subpart J requirements for sulfur plants.

EPA's response:

Based on your May 14, 1999, Generic Tail Gas Treatment Unit Flow Chart, Koch's TGTUs meet the definition of "reduction control systems". Each TGTU has attached to it an incinerator. Koch is burning refinery fuel gas and gas from the tail gas absorber in the TGTU incinerator. The exhaust from Koch's TGTU incinerators is a combination of exhausts from two different types of NSPS affected facilities (i.e., an SRU and an FGCD). Therefore, the TGTU incinerator is subject to both the H₂S limit for the fuel gas (§60.104(a)(1)) and the SO₂ limit for the exhaust from a reduction control system followed by incineration (§60.104(a)(2)(i)). The more stringent of the two limits applies (in this case, the FGCD limit) unless compliance can be determined independently for each requirement. Koch monitors the refinery fuel gas for H₂S prior to combustion and monitors the SO₂ levels in the exhaust from the TGTU incinerator. Since compliance for each requirement can be determined separately, Koch does not have to maintain the TGTU incinerator's combined emissions below the FGCD SO₂ emission level, but the SO₂ level (adjusted for the combustion of the fuel gas) must meet the limits under §60.104(a)(2)(i). This determination has already been established by EPA in an April 7, 1992 letter. (Enclosure 4)

Z. Propane Flare at Koch Pipeline Company Pipeline Terminal

Koch's Position:

NSPS Subpart J is inapplicable because this stream falls under the Subpart J exemption for process upset gas.

EPA's response:

Based on the description provided, EPA understands that the only time any vapors are generated and combusted at this terminal is during periods of shut-down or malfunction. As such, and if a part of the refinery, these gases are process upset gases excluded from Subpart J, but would still be subject to §60.11(d).

EPA also understands that this pipeline terminal is a separate source and is different from the refinery, and the only physical connection to the refinery is via a product pipeline. Since it does not appear to be part of the refinery, these vapors would not be a fuel gas because they are not generated at a refinery.

In your July 9, 1999, Supplemental Submittal, you requested that EPA Headquarters act on your proposed Alternative Monitoring Plan (AMP) and proposed Flare Gas Recovery Performance Policy at the same time as issuing this applicability determination. You state that if EPA does not act on those requests at the same time, you will assume that your requests would ultimately be denied. In our August 10, 1999, meeting, we made it clear that we are willing to work with you on those two requests, but they do not affect the applicability of the regulation. We are confident that we can resolve the issues relating to those two requests, and that your requests will be approved in some form, but it will take time to work out the remaining details. Therefore, we have decided not to delay our response to your original letter from August 14, 1998, while we continue to work together on the AMP and flaring policy.

This determination has been coordinated with EPA's Office of Regulatory Enforcement, the Emission Standards Division of the Office of Air Quality Planning and Standards, the Office of General Counsel, and Several of EPA's Regional offices. If you have any questions, please contact Tom Ripp of my staff at (202) 564-7003.

Sincerely,

S/ KEN GIGLIELLO for

John B. Rasnic, Director
Manufacturing, Energy and Transportation Division
Office of Compliance

cc: Jim Jackson, ORE
Diane McConkey, OGC
Jim Durham, OAQPS
Annette Lang, DOJ
Patrick Foley, Region III
Patric McCoy, Region V
Jonathan York, Region VI
Bill Peterson, Region VII
Lee Hanley, Region VIII
Paul Boys, Region X
Glenna Emanuel, OC

ALTERNATIVE MONITORING PLAN for NSPS Subpart J Refinery Fuel Gas

Conditions for Approval of the Alternative Monitoring Plan for Miscellaneous Refinery Fuel Gas Streams

Refinery fuel gas streams/systems eligible for the Alternative Monitoring Plan (AMP) should be inherently low in H_2S content, and such H_2S content should be relatively stable. The refiner requesting an AMP should provide sufficient information to allow for a determination of appropriateness of the AMP for each gas stream/system requested. Such information should include, but need not be limited to:

- A description of the gas stream/system to be considered including submission of a portion of the appropriate piping diagrams indicating the boundaries of the gas stream/system, and the affected fuel gas combustion device(s) to be considered and an identification of the proposed sampling point for the alternative monitoring;
- A statement that there are no crossover or entry points for sour gas (high H_2S content) to be introduced into the gas stream/system. (This should be shown in the piping diagrams);
- An explanation of the conditions that ensures low amounts of sulfur in the gas stream (i.e., control equipment or product specifications) at all times;
- The supporting test results from sampling the requested gas stream/system using appropriate H_2S monitoring (i.e., detector tube monitoring following the Gas Processor Association's: Test for Hydrogen Sulfide and Carbon Dioxide in Natural Gas Using Length of Stain Tubes, 1986 Revision), at minimum:
 - for frequently operated gas streams/systems - two weeks of daily monitoring (14 samples);
 - for infrequently operated gas streams/systems, 7 samples shall be collected unless other additional information would support reduced sampling.

Note: All samples are grab samples.

- A description of how the two weeks (or seven samples for infrequently operated gas streams/systems) of monitoring results compares to the typical range of H_2S concentration (fuel quality) expected for the gas stream/system going to the affected fuel gas combustion device. (e.g., The two weeks of daily detector tube results for a frequently operated loading rack included the entire range of products loaded out, and, therefore, should be representative of typical operating conditions affecting H_2S content in the gas stream going to the loading rack flare);
- Identification of a representative process parameter that can function as an indicator of a stable and low H_2S concentration for each fuel gas stream/system, (e.g., review of gasoline sulfur content as an indicator of sulfur content in the vapors directed to a loading rack flare);
- Suggested process parameter limit for each stream/system, the rationale for the parameter limit and the schedule for the acquisition and review of the process parameter data. The refiner will collect the proposed process parameter data in conjunction with the testing of the fuel gas stream's stable and low H_2S concentration.

The following shall be used for measuring H₂S in fuel gas within these types of AMPs unless the refiner requests, in writing, for approval of an alternative methodology:

- Conduct H₂S testing using detector tubes ("length-of-stain tube" type measurement);
- Detector tube ranges 0-10/0-100 ppm (N =10/1) shall be used for routine testing; and
- Detector tube ranges 0-500 ppm shall be used for testing if measured concentration exceeds 100 ppm H₂S.

Data Range and Variability Calculation and Acceptance Criteria

For each step of the monitoring schedule, sample range and variability will be determined by calculating the average plus 3 standard deviations for that test data set.

- If the average plus 3 standard deviations for the test data set is less than 81 ppm H₂S, the sample range and variability are acceptable and the refiner can proceed to the next step of the monitoring schedule.

Note: 81 ppm is one-half the maximum allowable fuel gas standard under NSPS Subpart J, and the Agency believes that using 81 ppm acceptance criteria provides a sufficient margin for ensuring that the emission limit is not exceeded under normal operating conditions.

- If the data shows an unacceptable range and variability at any step (the average plus 3 standard deviations is equal to or greater than 81 ppm H₂S), then move to Step 7. Agency approval is required to proceed to the next step if the average plus 3 standard deviations is between 81 ppm and 162 ppm H₂S. As an example, approval may be granted based on a review of the test data and any pertinent information which demonstrates that sample variability during the test period was due to unusual circumstances. Supplemental test data may be taken to demonstrate that process variability is within the plan requirements. Data may be removed from the variability calculations for cause after agency approval.
- For Steps 3 and 4, if the data shows an unacceptable range and variability (the average plus 3 standard deviations is equal to or greater than 81 ppm H₂S), the source will drop back to the previous step's monitoring schedule.
- If at any time, one detector tube sample value is equal to or greater than 81 ppm H₂S, then begin sampling as specified in Step 6. Note: Standard deviation cannot be calculated for a data set containing one point.

Monitoring Schedule for Approved AMPs

For gas streams which must meet product specifications for sulfur content, one time only detection tube sampling along with a certification that the gas stream is subject to product or pipeline specifications is sufficient for the AMP. If the gas stream composition changes (i.e., new gas sources are added), or if the gas stream will no longer be required to meet product or pipeline specifications, then the gas stream must be resubmitted for approval under the AMP.

The following are examples of streams needing one time only monitoring:

- Certified commercial grade natural gas;
- Certified commercial grade LPG;
- Certified commercial grade hydrogen;
- Gasoline vapors from a loading rack that only loads gasoline meeting a product specification for sulfur content.

For other gas streams, the H_2S content of each refinery fuel gas stream/system with an approved AMP shall be monitored per the following schedule:

Step 1:

The refiner will monitor the selected process parameter for each stream/system, according to the established process parameter monitoring or review schedule approved by the agency in the AMP, and at times when conducting H_2S detector tube sampling.

Step 2:

The refiner will conduct random detector tube sampling twice per week for each stream/system for a period of six months (52 samples). For fuel gas streams infrequently generated and combusted in affected fuel gas combustion devices (i.e., less frequent than bi-weekly), detector tube samples shall be taken each time the fuel gas stream is generated and combusted. A total of at least 24 samples shall be collected for infrequently generated gas streams. Monitor and record the selected process parameter in accordance with the established schedule, and at times when conducting H_2S testing. Move to Step 3 if the calculated range and variability of the data meets the established acceptance criteria. Submit test data (raw measurements plus calculated average and variability) to the agency quarterly.

Step 3:

The refiner will conduct random H_2S sampling once per quarter for a period of six quarters (6 samples) with a minimum of 1 month between samples. A minimum of 9 samples are required for infrequently generated and combusted fuel gas streams before proceeding to Step 4. Continue to monitor and record the selected process parameter in accordance with the established schedule, and at times when conducting H_2S testing. Move to Step 4 if the calculated range and variability of the data meets the established acceptance criteria. Submit test data (raw measurements plus calculated average and variability) to the agency quarterly.

Step 4:

The refiner will conduct random H_2S sampling twice per year for a period of two years (4 samples); sample randomly in the 1st and 3rd quarters with a minimum of 3 months between samples. Continue to monitor and record the selected process parameter in accordance with the established schedule, and at times when conducting H_2S testing. Move to Step 5 if the calculated range and variability of the data meets the established criteria. Submit test data (raw measurements plus calculated average and variability) to the agency semiannually.

Step 5:

The refiner will continue to conduct testing on semi-annual basis. Testing is to occur randomly once every semiannual period with a minimum of 3 months between samples. Continue to monitor and record the selected process parameter in accordance with the established schedule, and at times when conducting H₂S testing. If any one sample is equal to or greater than 81 ppm H₂S, then proceed to the sampling specified in Step 7. Note: Standard deviation cannot be calculated for a data set containing one point.

Step 6:

If, at any time, the selected process parameter data indicates a potential change in H₂S concentration, or a single detector tube sample value is equal to or greater than 81 ppm H₂S, then the fuel gas stream shall be sampled with detector tubes on a daily basis for 7 days (or for infrequently generated gas streams - 7 samples during the same period of an indicated change in H₂S concentration, or as otherwise approved by the agency). If the average detector tube result plus 3 standard deviations for those seven samples is less than 81 ppm H₂S, the date and value of change in the selected process parameter indicator and the sample results shall be included in the next quarterly report, and the refiner shall resume monitoring in accordance with the schedule of the current step. If the average plus 3 standard deviations for those seven samples is equal to or greater than 81 ppm H₂S, sampling shall follow the requirements of Step 7.

Step 7:

If sample detector tube data indicates a potential for the emission limit to be exceeded (the average plus 3 standard deviations is equal to or greater than 81 ppm H₂S), as determined in the Data Range and Variability Calculation and Acceptance Criteria or in Step 6, the refiner shall notify the agency of those results before the end of the next business day following the last sample day. The fuel gas stream shall subsequently be tested daily for a two week period (or 14 samples during the same event or as otherwise approved by the agency for infrequently generated gas streams). After the two week period is complete, sampling will continue once per week, until the agency approves a revised sampling schedule or makes a determination to withdraw approval of the gas stream/system from the AMP. Note: At any time, a detector tube value in excess of the 162 ppm limit is evidence that the emission standard has been exceeded.

General Provisions of Approved AMPs

Upon agency request, the refiner shall conduct a test audit for any gas stream with an approved AMP. The audit shall consist of daily detector tube samples collected over a one week period (7 samples). For fuel gas streams infrequently generated and combusted in affected fuel gas combustion devices, an audit shall consist of 3 consecutive sampling events. (e.g., Rail loading may occur once per month, an audit would consist of 3 consecutive loading events.) The United States Environmental Protection Agency, with due notice, reserves the right to withdraw approval of the AMP for any gas stream/system.

The source shall keep records of the H₂S detector tube test data and the representative process parameter data and fuel source for at least two years.

If a new fuel gas stream is introduced into a fuel gas stream with an approved AMP, the refiner shall again apply for an AMP and repeat Steps 1 - 5.

Example:

An AMP Application for a Hydrogen Plant PSA Off-Gas Stream Combusted Exclusively in the Hydrogen Plant Process Heater:

Process Description

Hydrogen production for the refinery by the steam methane reforming process. CO_2 is the primary impurity in the hydrogen produced; small amounts of CO and methane are also present. Unpurified hydrogen is passed over molecular sieve absorbent beds to remove these impurities. The off gas from regeneration of the absorbent beds is called PSA off-gas. It is sent to the hydrogen plant heater to recover heat and control CO emissions.

Piping Diagrams

Piping diagrams should be supplied to show monitoring location and to demonstrate that there is no potential for cross over or entry points for sour gas.

Basis for PSA Off-Gas Low H_2S Content

Since PSA off-gas is a byproduct of hydrogen purification, any H_2S in the PSA purge gas must come from the hydrogen unit feed. Levels of H_2S in the PSA gas are negligible because H_2S must be controlled to prevent deactivation of the unit's catalyst

H_2S is a permanent catalyst poison. The hydrogen unit has 2 scrubbers to remove H_2S from the feed gas to protect the unit's catalyst from H_2S poisoning. The scrubbers are operated in series. The lead scrubber must exhibit at least a 70% reduction in H_2S content. If not, the scrubber is taken off line and the absorbent is replaced. After the absorbent is replaced, the scrubber is placed on line as the second scrubber in series. This maximizes the amount of H_2S removal and assures maximum scrubbing potential when one scrubber is off line for absorbent replacement.

Process Parameter Monitoring and Suggested Process Parameter Limit

Operation of the scrubbers is checked on a monthly basis with detector tubes. The feed gas H_2S content is measured at the inlet and outlet of the lead scrubber. If natural gas is used as hydrogen plant feed; both readings are below the 1 ppm detection limit. If refinery fuel gas is the feed gas, 30 ppm to 40 ppm H_2S is normally detected at the inlet. A lead scrubber outlet reading of 10 -12 ppm H_2S would trigger absorbent replacement. The suggested process parameter limit is 20 ppm H_2S at the lead H_2S absorber outlet. Absorber outlet H_2S measurements will be taken in conjunction with the PSA gas measurements during Steps 2 and 3.